Lessons Learnt in Implementation of Coordinated Voltage Control Demonstration

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Abstract

In this paper, the challenges for integrating smart substation automation system into traditional substation is presented. The preparation of a long-term field demonstration for coordinated voltage control in distribution grid in western Denmark is used as a case study. The paper also briefly describes the functionality (the methodology for the implemented voltage control), operating principle and the components of the automation system with the required testing for each part of the system. The control system is installed in parallel with existing Automatic Voltage Regulation (AVR), with only few additional components. The objective of the smart control system is to increase the grid hosting capacity for distributed generation, to reduce network losses, to enhance voltage quality, and to postpone network reinforcement needs. The aim of this paper is to share the experiences of the field demonstration implementation, to emphasize the importance to reduce the gap between academic research and reality, and to propose a comprehensive testing methodology for successful field demonstration. The paper also highlights additional questions to be solved when the algorithms and prototype devices are taken into field.

1 Introduction

The growth of small and large-scale Distributed Generation (DG) is changing the traditional distribution grid in many ways. Simultaneously, the load demand is also increasing due to heat pumps and the share of electric transportation are expected to be exponential in the future [1]. The grid already is and has a rising number of possibilities to develop from passive network to more flexible and controllable. The utilization of demand response, self-generation, and storage will allow the Distribution System Operator (DSO) to postpone reinforcements but also customer to have more control on their electricity consumption and thereby have a direct impact to their carbon footprint and costs.

There are few main reasons for the evolution. In Nordic countries, carbon-free goals are driving the replacement of fossil fuel usage and direct electric heating. The future grid, where a major part of connections are consisting smart houses, prosumers, microgrids and Renewable Energy Sources (RES) are the main driver for the development of smart grids and advanced automation solutions. The grid automation is also beneficial for the reliability of electricity transmission and distribution e.g., fault detection, to enable more microgrids and energy communities, to collect real-time network data to observe network condition and to utilize the collected data by e.g., performing predictive maintenance. Advanced automation solutions can also have a huge financial impact for DSO by postponing reinforcement needs, increasing hosting capacity, reduce network losses, degradation of voltage level quality and to reduce operational actions from easily worn devices [2].

The focus of the Optimal Voltage Regulation (OVR) project is to utilize previously designed state estimation [3] and optimization [2] algorithms to develop and demonstrate a smart voltage regulation system that will optimize the voltage level in whole distribution grid to minimize grid's operational costs (losses and maintenance) and to increase the hosting capacity of distribution network and postpone the grid reinforcements [4]. The demonstration focuses on secondary voltage control of the AVR of the On-Load Tap Changer (OLTC) using network-wide information. The control system will enhance the hosting capacity of distribution network for DG and other Distributed Energy Resources (DERs) like electric vehicles, heat pumps and electricity storage.

The aim of the paper is to analyze the functional and non-functional adversities faced after the laboratory testing and installation testing has been completed successfully. The main focus is on what kind of challenges were found out during the start-up testing phase i.e., open-loop testing. The paper points out how those were found out and try to explain why those were not found out during the laboratory or installation tests. The solutions to reach independent smart coordinated voltage system are provided as well.

2 Overview of the Control System

In this chapter, the optimal coordinated voltage control system is briefly described. The control system utilizes the hardware already installed at the medium voltage substation (60/10 kV) with only few additional computing and communication components and making active use of smart meter data. The main functionalities hosted in Substation automation Unit (SAU) [4] are production and load forecasting, network State Estimation (SE) and Optimal Power Flow (OPF) calculation. In addition, SAU also hosts functionalities to ensure decent quality of data, logging and collection of historical data and based on the control algorithms results, SAU provides the setpoint for substation busbar voltage. The system functionalities are presented in Fig. 1. Data logger provides the feeder current measurements for SAU. In addition, Safe mode device provides the advanced system reliability and controllability for DSO. Parallel operation of AVRs is the backup for all the safety and security features. It prevents network voltage level violations if all other safety features fail [5].

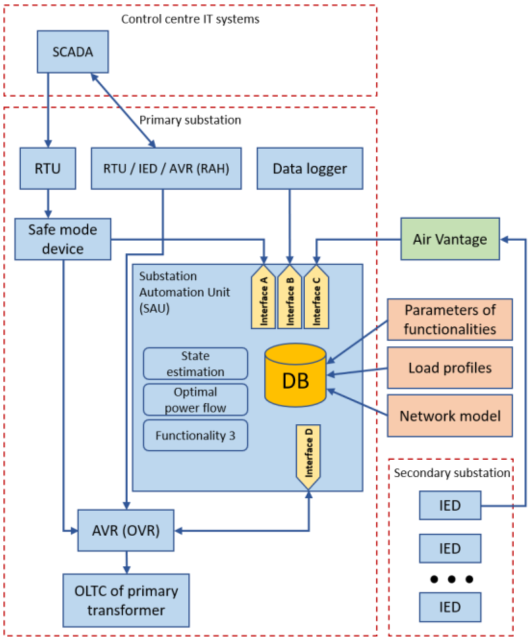

Figure 1. System functionalities and communications

The data logger provides the feeder current measurements for SAU since the RAH cyber security policy prevented the direct connection to their Local Area Network (LAN) from non-certified devices. Other solutions for measurements were considered, but the delay and resolution were in unacceptable levels for real-time control system. 4G modem is utilized for receiving secondary substation measurements but also for remote monitoring and control of the system.

The system needs to continue operating correctly even if there is a communication issue or power system disturbance or failure, and the system should prevent the control violating network limits or causing the hunting of OLTC. In traditional substation hunting is not a problem. But with two parallel AVRs without proper safety precaution the two may start to counteract with each other's control decisions. Even with a smart control system failure, the sufficient voltage level must be maintained, and the networks state needs to be restored. Network topology changes, voltage dips or other voltage quality issues, and grid operational issues like continuation of grid operation during earth faults, manual control of OLTC and possibility to stop the operation of SAU in any moment are needed to be considered in the design of smart control system. Safe mode device is preventing all these problems. The simplicity of the device improves the reliability, and it is not prone to defects of other systems failures.

2.1 Laboratory Testing

In the laboratory, the system components were tested separately i.e., algorithm testing, unit testing but also system testing. The laboratory testing setup was built to be as similar as possible as the real operating environment. All the features were tested and verified with hardware-in-the-loop testing. The verification consisted of controller interactions and the developed safety features, and system reliability against e.g., SAU blackout. To achieve reliable, independent system and controllability for the DSO, Safe mode device was developed. In short, it prevents the system to violate network limits if the active control is unavailable, the DSO has foreseen topology changes or otherwise does not trust the smart control system. Safe mode device automatically changes the control mode from active to passive, fixed voltage setpoint i.e., mimics the traditional control scheme of RAH AVR when activated. Safe mode device allows the smart functionalities to be running without constant supervision since the hardware and software design has a fail-safe implementation [6]. This methodology was selected since the SE and OPF are utilizing fixed grid model in the calculations. Dynamic grid topology could be possible by integrating Distribution Management System (DMS) and SAU to exchange information about the status updates of switching devices. However, in the scope of the project this integration was not realized. For the future development this is possible since the data stored in SAU meets the latest standard data models i.e., IEC 61850 and IEC Common Information Model (CIM) [4]. This enhances system interoperability and ensures scalability.

2.2 Field Testing

System functionalities were tested and verified to be operating before taking the system into the substation. However, every system operability should be verified in their natural operating environment, to certify all the functional and non-functional features of the smart control system. Full system assembly may not always be possible before field testing. In this case, e.g., SCADA control through RTU cannot be done beforehand nor the remote measurement reading, or substation LAN communication. Field testing is the final testing method to ensure interoperability, safety, and reliability of the substation automation system.

3 System Deficiencies

The optimal voltage control system went through comprehensive testing procedure including algorithm testing, unit testing, system testing, hardware-in-the-loop testing and finally field testing at the operational environment at the substation [5]. All features were working as planned, and zero malfunctions were observed. When the local DSO had accepted all the operational and safety features developed and tested, the system was installed at the substation. Despite successful testing after installation, several unforeseen problems arose when the demonstration was set to launch.

3.1 Feeder Current Measurements

Feeder current measurement system consists of National Instruments cRIO-9039 and the current measurement instrument Magnelab RCS-1800 with appropriate current rating on each feeder. The measurement instrument requires high currents resulting accurate reading that the verification of the whole linear range is not practically possible in laboratory (up to 1000 A). However, the appropriate testing signal was injected into the data logger interface and the logged data was verified to match with the input signal. However, when taking the system into field one of the measurements, feeder 9 as shown in Fig.2., began to provide random, unexplainable measurement errors. After troubleshooting and debugging, the conclusion was that the defective operation was a software related issue rather than hardware.

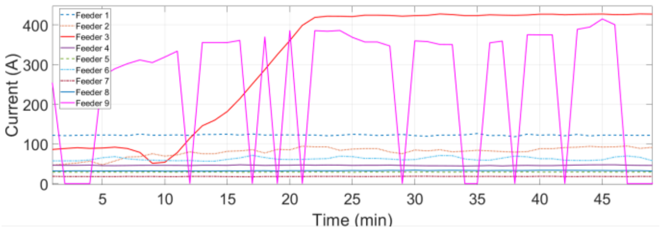

Figure 2. Erroneous primary substation feeder measurement

After verifying the functionalities of hardware and measurement software, the source of the error was originated to be syntax error between the server initialization in LabVIEW and MMS Server SCL-file.

3.2 Real-time Measurements

Few secondary substation real-time measurement locations had a difference between the grid model and the physical. The consequence was noticed in the state estimation i.e., because of an open switch, the Power Quality (PQ) meter providing the real-time measurement is not part of the monitored grid and thus the measured values are not corresponding the estimates. When the meter locations in the model and on-site were double checked and necessary location changes had made in the field, the verification of the measurements were conducted successfully.

Two secondary substation measurements were found to be continuously zero. There were three possible sources of errors: AirVantage client in SAU, AirVantage server, or meters themselves. The mapping of real-time measurements in SAU were known to have high probability for misconfigurations since the mapping required manual work and is thus likely to face human errors. Despite this, the problem was originated to be in the real-time measurement's hardware or software and not a mapping error.

Another error was found with the modems forwarding readings from the PQ-meters into AirVantage. The modems update rates are set to provide measurement data with one-minute interval. However, some of the modems occasionally skip this interval and tries to transmit as fast as possible (3-4 times per second). This problem remains unsolved and a most brutal workaround is required: reboot of the malfunctioning modems. The most probable cause for the error was originated to be a race condition within the modem firmware.

3.3 Distribution Network Information

A general problem with traditional distribution system documentation is to have timeliness and complete information of the grid. The issues may remain undetected with the traditional operating mode of the grid since there is not enough measurements for the state estimation to indicate the model correspondence of all parts of the grid. When using the same grid information for smart grid applications, inconveniences emerge. The problem may be due to change of employees or lack of knowledge on standards.

The Common Information Model (CIM) is a standardized model (IEC 61970 & IEC 61968). Standard defines the principle for indexing i.e., defining the tap position for nominal turns ratio. The network model turned out not to be CIM compliant i.e., the indexing was not correct. Solution alternatives included the manual work for verifying all tap positions to be CIM compliant or converting the measurements to medium voltage side of the secondary substations. The latter results to removal of all secondary transformers from the grid model in SAU.

This solution would have an inevitable negative impact to the success of the demonstration since the bandwidth for the substation voltage control would be reduced and the probability for non-converging OPF calculation will increase. The allowed substation voltage setpoint bandwidth is determined based on historical data and the agreed setpoint bandwidth is set to be on a safe side of the historical maximum and minimum deviation to prevent any voltage level violations. At worst, the grid model modification could make the demonstration useless i.e., reduce the bandwidth too narrow to have nothing to control. The impact could have been verified with the off-line testing of the complete system. However, since the solution had multiple uncertainties it was disregarded, and the only viable solution for this issue was to visit physically on each secondary substation and verify the current tap position to be CIM compliant. Example of a station voltages is shown in Fig. 3. The Figure shows the primary substation voltage measured by AVR (Tapcon), the secondary substation voltage on medium voltage side measured by PQ meter before correction (AirVantage), PQ voltage measurement after correction (AirVantage +2.5 %) and estimated voltage (Estimate). The 2.5 % correction need reflects that the turns ratio for the measured substation's transformer is incorrect in the network model.

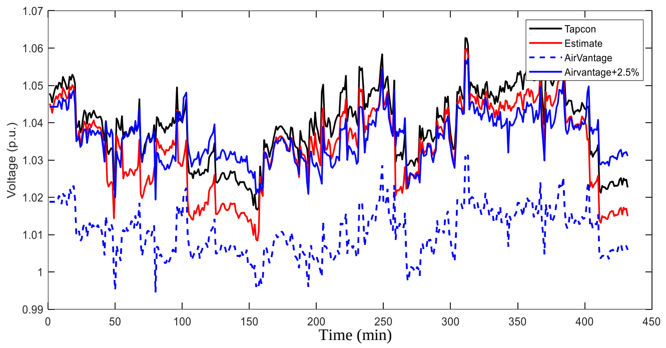

Figure 3. Comparison of different voltage data sources from certain station

The AirVantage client, which is providing real-time measurements for SAU, had some constant offset between measured (AirVantage) and estimated data. The test was realized without utilizing corresponding PQ-measurement in the state estimation. The reason for the offset was incorrect off-load tap changer position of corresponding distribution transformer in the grid model. Voltage measurements are realized on low voltage side of distribution transformer and therefore the tap position has impact for the state estimation. After verifying the correct position on site, the grid model was updated which had +2.5 % (one tap position) impact on measured voltages. A long-term observation for the data was made to ensure the accuracy of voltage estimations.

3.4 State Estimation

Multiple algorithms have been presented in the literature e.g., node voltage based, branch current based, hybrid particle swarm and interior point optimization etc. For the project, the branch current based method was selected since it has been designed especially for distribution network, is relatively fast and handles current measurements effectively. Furthermore, for large-scale implementation of smart grid, the state estimation is necessary. Branch current method fulfills all the estimation requirements for future smart grids: efficient calculation of weakly meshed networks, utilization of secondary substation and smart meter measurements, fast computing time, and capability for three-phase calculations [7]. Critical part of the implemented coordinated voltage control solution is the knowledge of network state in each section. The optimal voltage control relies heavily on accurate state estimation. The SE is based on primary substation measurements i.e., feeder currents and bus voltage, few real-time measurements from secondary substations and pseudo measurements i.e., customer load profiles based on historical data. In Fig.4. the SE error on CHP feeder is presented. In subfigure a, the results seem to be in line with the measurements. The current estimation without the measurement (blue) has a correct magnitude with variation that is not present in the CHP measurement (orange). The variation is a consequence of the modelled load projected to the feeder. More accurate analysis of the feeder SE is shown in subfigure b. Due to deviance in the current measurements, the load estimate falls to be highly inaccurate, i.e., the estimate is up to three times higher compared to the modelled. The estimation error results in infeasible constraints for OPF.

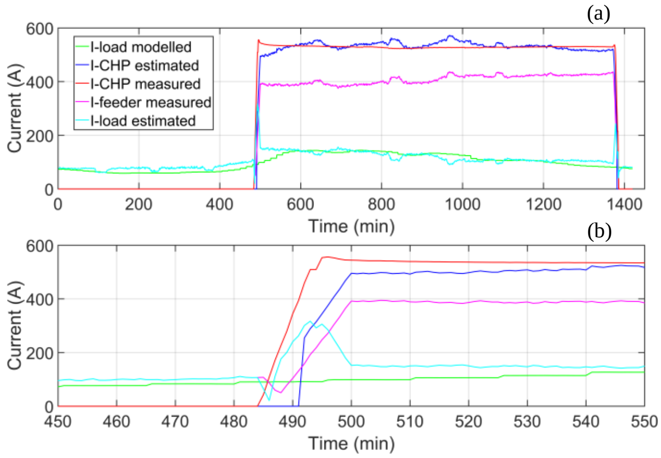

Figure 4. CHP feeder currents: (a) Overview (b) Analysis of the CHP start-up

Difference between primary substation current measurement (feeder 3) and PQ-meter reading at the CHP plant was the most probable cause to the problem since the substation measurement was made by averaging 1-second RMS values to one minute and the real-time measurements are instantaneous values. The data logger measurement verification was made by using SFTP protocol to update the measuring software to provide 1s RMS values to SAU. The validation of primary substation's CHP feeder current measurement is shown in Fig.5. Data logger measurements are compared to with SCADA measurements. A closer look for the ramp-up period was carried out and no deviation between the data logger and SCADA measurements was observed.

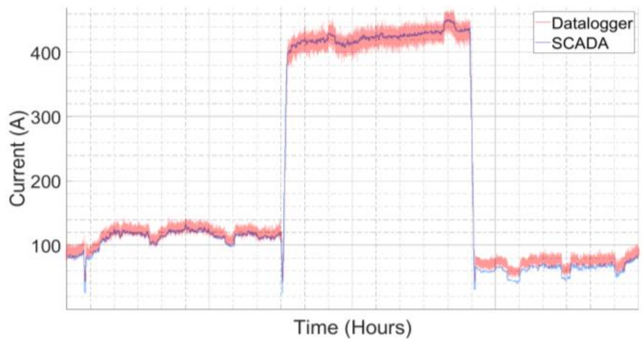

Figure 5. CHP feeder current measurement validation

The SE error remained the same and the PQ-meter settings at the CHP plant is under investigation for erroneous measurement since the primary substation measurements were confirmed to be accurate. The generator type or network parameters, e.g., shunt capacitances may have an impact to the ramp-up slope measured by data logger.

In summary, SE errors were the most problematic from the control perspective because of multiple simultaneous errors. The nature of the errors also made the identification of the source challenging. As described, the solution was to go through all the data gathered for SE and rule the effects of erroneous data out one by one.

4 Conclusion

The rapid development in distribution grid is encouraging new smart control systems to be developed. Academic research has provided countless amount of smart grid related theoretical studies but only fraction of these have been implemented in a real demonstration.

Smart functionalities alone are not a guarantee for the success of implementation. The functional and non-functional deficiencies and bottlenecks for the system operability and reliability are usually elsewhere. A new holistic System of Systems (SoS) thinking is required. Smart control functionalities consist of multiple subsystems, which all need to operate properly independently but also system level. Subsystem reliability has an impact to whole system reliability. Traditional testing practices must adapt to ensure the introduction of futures complex energy systems. Functional and non-functional testing needs to include normal operation but especially multiple exceptional conditionals with variety of situations within normal and extreme conditions of all parts of the system. Safety, emergency and monitoring functionalities needs to be designed accordingly, i.e., preventing, or significantly reducing the probability of hazardous situations to ensure safety and reliability. These results are extremely important in real-life grid operation. The outcome may limit the implementation of the smart functionalities or the complexity rises. In a worst case, the theoretical functionalities are not feasible to implement with the technology available, which makes the idea useless.

Academic studies usually make unrealistic assumptions for proofing the smart functionalities: perfect communication (no delay), accurate, instantaneous measurement data always available and no human errors and always up to date grid data documentations and configuration of devices. To narrow down the gap between academic research and practice, the most promising research outcomes should be developed always considering the practical limitations in real-life conditions.

Methodological development for field testing of complex smart grid systems is needed. The results and usability of these advanced control algorithms can only be validated by installing the system to its natural operating environment. This provides proof of reliable smart control system, but the developed solutions must also be profitable for the DSO taking the risk with the installation and demonstration. System should provide revenue or profit (reduce losses, increase hosting capacity etc.) according to existing grid regulation. The value of field tests to achieve robust system implementation instead of optimal control should be increased as a final proof of developed solution.

5 Acknowledgements

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